



**WIND INTERMITTENCY AND  
THE PRODUCTION TAX CREDIT:  
A HIGH COST SUBSIDY FOR LOW VALUE POWER**

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## EXECUTIVE SUMMARY

The United States has subsidized the wind industry for 35 years.<sup>1</sup> The subsidies began with the Public Utility Regulatory Policy Act (PURPA) and Energy Tax Act (ETA) of 1978. Subsequently, with passage of the Energy Policy Act of 1992 (EPAct) wind subsidies were increased through a variety of programs, most prominently the federal production tax credit (PTC).<sup>2</sup> In many electric markets, the value of the PTC tax subsidy is greater than the price of electricity itself.

Today, many in Congress are debating whether it makes sense to continue subsidizing wind, including the Senate's proposed one-year, \$12.2 billion<sup>3</sup> extension, given the Nation's mounting debt, and the harm to conventional generation resources required to maintain reliability. In connection with this debate, this paper examines relevant electric system operational and reliability data in order to assess the consumer value of the subsidies and the actual operational performance of PTC-subsidized wind generation relative to consumer demand for electricity. We find that the vast majority of the Nation's wind resources fail to produce any electricity when our customers need it most, and that the subsidy is adding billions of dollars of hidden costs while undermining the reliability of the grid.

Most Americans intuitively understand that wind power is intermittent: wind turbines do not generate electricity when the wind does not blow. However, few understand the degree to which these resources fail to operate when our customers use the most electricity. Production data from the Nation's grid clearly illustrate that wind's intermittency problem is severe and getting worse. Our analysis of almost four years' of generation data in the Electric Reliability Council of Texas (ERCOT—over 10,000 MW of wind capacity), the Midwest ISO (MISO—almost 12,000 MW of wind capacity), and PJM Interconnection (PJM—over 5,000 MW of wind capacity), demonstrates that:

- In all three regions, *over 84% of the installed wind generation infrastructure fails to produce electricity when electric demand is greatest*, as shown in Table EX-1.

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<sup>1</sup> In thirty states plus the District of Columbia, wind generators also receive state-funded production subsidies.

<sup>2</sup> More recently, payments to the wind industry have increased still further with billions of dollars in additional monies paid-out as part of the \$831 billion American Recovery and Reinvestment Act of 2009 (ARRA).

<sup>3</sup> Congressional Joint Committee on Taxation, August 3, 2012.

Region	Median Availability Peak Hr, Highest 10 Demand Days	Median Availability All Days, All hours
ERCOT	6.0% - 15.9%	30.9%
MISO	1.8% - 7.6%	27.0%
PJM	8.2% - 14.6%	25.9%

**Table EX- 1: Wind Performance, Peak Demand and Average**

As this table highlights, in MISO, just **1.8% and 7.6%** of wind capacity was available and generating power during the peak hours on the highest demand days. In ERCOT, **6.0%** and **15.9%** generated power, and in PJM, the range was between **8.2%** and **14.6%**. These availability values are significantly lower than median availability for the entire period.

- The July 2012 heat wave in Illinois, where temperatures soared to 103 degrees in Chicago, provides a compelling example of wind generation's failure to perform when needed most. During this heat wave, Illinois wind generated less than 5% of its capacity during the record breaking heat, producing only an average of 120 MW of electricity from the over 2,700 MW installed. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago averaged 22,000 MW, the average amount of wind power available during the day was a virtually nonexistent 4 MW.<sup>4</sup>
- The greatest amounts of wind generation occur in the Spring and Fall, when the demand for electricity is lowest, and the smallest amounts of wind generation occur in Summer, when the demand for electricity is greatest. Wind generation data in PJM, the Nation's largest independent grid operator shows that the "load-wind gap" (i.e. the difference between summer electricity demand and summer wind availability, relative to their respective annual averages) was almost **-70%** in Summer 2010 and 2011. In Summer 2012, the load-wind gap was **-59%**.
- The costs of integrating intermittent wind generation onto the power grid, including backing up wind power with gas-fired generation, and ensuring

<sup>4</sup> J. Lesser, "Wind Power in the Windy City: Not There When Needed" *Energy Tribune* (op-ed) July 25, 2012. (Another example of wind generation variability took place this month on October 16, 2012 when wind generation on the Bonneville Power Administration system was 4,300 MW, accounting for 85% of total generation in the pre-dawn hours. The next day, wind generation was practically non-existent falling to almost zero electric generation. See "In a first, wind exceeds hydro in BPA region," Platt's *Megawatt Daily*, October 19, 2012, p. 9).

that fluctuating wind power levels do not affect the power system “quality” are at least an additional \$500 million per year nationwide, and increasing. Moreover, forecasting wind availability, even for the next day, continues to be problematic, resulting in frequent violations of federal reliability standards because of wind’s highly volatile production from hour-to-hour. And, these costs do not include the billions of dollars spent to construct additional transmission lines needed to bring geographically dispersed wind power to customers.

The intermittency of wind power, and the clear patterns of the lowest wind availability when electricity demand is highest, also refutes some PTC proponents’ claims that subsidized wind generation “benefits” consumers by artificially suppressing market prices. Such claims are examples of “free lunch” economics that lack any credibility.<sup>5</sup> While subsidized wind may artificially suppress market prices in the short-run, markets are quick to respond. Consequently, any short-run consumer “benefits” quickly become long-run costs, as subsidies create lasting distortions resulting in consumers paying even more for their electricity.

The failure of wind to perform during times of peak demand has far reaching impacts. Electricity is the ultimate “just-in-time” resource. Because electricity cannot be stored cheaply, the power system requires resources that produce electricity when called upon. Conventional power plants—nuclear, coal, gas—as well as hydroelectric dams that store water, are the backbone of the electricity system because they share two critical characteristics: predictability and reliability. Absent rare equipment failures, they run reliably whenever needed. In stark contrast, as previously described, wind generation is neither predictable nor reliable. The evidence demonstrates that wind is not available when customers need electricity and no one can predict whether or when the wind will blow a week from today, let alone a year from today.

Finally, like all subsidies, the PTC is economically inefficient. Subsidies distort competitive markets, drive out unsubsidized competitors, and reduce the incentives to innovate and improve efficiency.<sup>6</sup> The wind PTC encourages inefficient investment: with a before-tax

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<sup>5</sup> See, R. Caperton, “Wind Power Helps to Lower Electricity Prices,” Center for American Progress, October 10, 2012. <http://www.americanprogress.org/issues/green/report/2012/10/10/41100/wind-power-helps-to-lower-electricity-prices/>.

<sup>6</sup> See F. Huntowski, A. Patterson, and M. Schnitzer, “Negative Electricity Prices and the Production Tax Credit,” The Northbridge Group, September 14, 2012. [http://www.nbgroup.com/publications/Negative Electricity Prices and the Production Tax Credit.pdf](http://www.nbgroup.com/publications/Negative_Electricity_Prices_and_the_Production_Tax_Credit.pdf). See also, Testimony of Public Utilities Commission Chairman Donna Nelson, Before

credit of \$34/MWh, the wind PTC provides a powerful investment incentive, even when wholesale markets show a capacity surplus. And, because wind generation is least available when needed most, wind generation imposes additional costs on the power system. More conventional resources must be available to make up for sudden changes in wind production and power system operators incur additional costs to ensure that electric demand and supply are always matched. Even if one argued that wind generation was worthy of temporary subsidies when PURPA was enacted, surely after 35 years, the “infant” wind industry is fully grown.

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(cont.)

the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from <http://www.senate.state.tx.us/avarchive/>.

## I. INTRODUCTION

Twenty years ago the Energy Policy Act of 1992 (EPAct) introduced the federal production tax credit (PTC) to further promote renewable energy development initiated under the Public Utility Regulatory Policy Act (PURPA) and the Energy Tax Act (ETA) of 1978.. The PTC currently provides wind generation owners with an after tax credit of 2.2 cents per kilowatt-hour (kWh) for the first ten years of operation,<sup>1</sup> meaning each year’s “tranche” of wind generation is eligible for ten years’ of payments for each kW of power produced regardless of whether the power is needed.

Although not specifically limited to wind generation, approximately 75% of the total PTC credits claimed to date have been for wind generation.<sup>2</sup> Today, Congress is currently debating whether to extend the “temporary” PTC for an additional year, at a cost to taxpayers of \$12.2 billion. The one-year extension would mean that wind generation completed or under construction in 2013 will receive this significant subsidy for the next ten years.

Subsidies by their nature distort markets and are economically inefficient; the PTC is no exception. However, the magnitude of the PTC subsidy—far larger than any other form of production based energy subsidy<sup>3</sup>—has especially egregious impacts on wholesale electric markets. The reason is that wind power generates the least amount of power during Summer, when the demand for and value of electricity is greatest, and the most power during Spring, Fall and at night, when the demand for and value of electricity is lowest. Thus, not only does the PTC distort wholesale electric markets by suppressing prices, it also forces consumers and taxpayers to pay billions of dollars each year for electricity that has little economic value and, in many hours, has negative value.<sup>4</sup> In essence, the wind PTC

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<sup>1</sup> This credit is equivalent to approximately 3.4 cents/kWh on a pre-tax basis, based on the 35% federal corporate income tax rate. When it was first introduced as a “temporary” provision of the U.S. tax code, the PTC provided a credit of 1.5 cents/kWh of wind power generated.

<sup>2</sup> M. Sherlock, CRS. “Impact of Tax Policies on the Commercial Application of Renewable Energy Technology,” Statement Before the House Committee on Science, Space, and Technology, Subcommittee on Investigations and Oversight & Subcommittee on Energy and Environment, April 19, 2012, p. 3.

<sup>3</sup> U.S. Energy Information Administration, “Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010,” July 2011. [www.eia.gov/analysis/requests/subsidy/](http://www.eia.gov/analysis/requests/subsidy/).

<sup>4</sup> F. Huntowski, A. Patterson, and M. Schnitzer, “Negative Electricity Prices and the Production Tax Credit,” The Northbridge Group, September 14, 2012. [http://www.nbggroup.com/publications/Negative\\_Electricity\\_Prices\\_and\\_the\\_Production\\_Tax\\_Credit.pdf](http://www.nbggroup.com/publications/Negative_Electricity_Prices_and_the_Production_Tax_Credit.pdf). See also, Testimony of Public Utilities Commission Chairman Donna Nelson, Before

is the electric industry equivalent of paying farmers to grow low-value crops and plow under high-value ones.

Our comprehensive analysis of wind generation over the period January 2009 through August 2012 shows that wind generation has consistently exhibited this economically backward pattern in the regions of the country where over 60% of all wind capacity is installed. Thus, our analysis demonstrates that this economically backward pattern, in which only 20% of the installed wind generation actually produces any power in Summer when the demand for electricity is greatest, is neither a temporary nor a local aberration.

As the PTC continues to subsidize construction and operation of more wind power, it imposes ever greater costs, not just in terms of the large dollar value of the subsidies themselves, but also through increasingly large economic “spillover” impacts. These impacts hurt competitive wholesale electric markets by damaging the economic viability of traditional generating resources that can be dispatched as needed, and increasing the costs incurred to “firm-up” non-dispatchable, unreliable wind power. Texas, with over 10,000 MWs of installed capacity, the most of any state, is beginning to understand how the PTC has undermined Texas reliability:

Federal incentives for renewable energy ... have distorted the competitive wholesale market in ERCOT. Wind has been supported by a federal production tax credit that provides \$22 per MWH of energy generated by a wind resource. With this substantial incentive, wind resources can actually bid negative prices into the market and still make a profit. We’ve seen a number of days with a negative clearing price in the west zone of ERCOT where most of the wind resources are installed ... The market distortions caused by renewable energy incentives are one of the primary causes I believe of our current resource adequacy issue ... [T]his distortion makes it difficult for other generation types to recover their cost and discourages investment in new generation.<sup>5</sup>

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(cont.)

the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from <http://www.senate.state.tx.us/avarchive/>.

<sup>5</sup> Chairman Donna Nelson testimony before the Texas Senate Natural Resources Subcommittee (September 6, 2012), transcribed from <http://www.senate.state.tx.us/avarchive/> (emphasis added).

## II. WIND SUBSIDIES: 35 YEARS AND COUNTING

The first OPEC oil embargo in 1973 is best remembered for the widespread turmoil it caused for consumers, who suddenly found themselves waiting in long lines to fill their vehicles' gas tanks. But a more lasting legacy of that embargo was the 1978 regulatory efforts to address increasing concerns that the U.S. was running out of oil and natural gas resources.

At the time, natural gas prices were fully regulated. Existing price caps had deterred new exploration and led to decreasing natural gas supplies as production from existing wells declined and growth stagnated. Many predicted complete supply exhaustion within the next decade.

To address these increasing energy supply fears, Congress passed the National Energy Legislation of 1978, which incorporated five major legislative acts, including PURPA. PURPA was designed to both encourage energy conservation and force electric utilities to purchase electric power from “qualifying” independent power producers—primarily renewable energy providers. Under PURPA, state utility regulators set contract prices based on forecasts of utilities' “avoided” costs, that is, the marginal cost of electricity the regulators predicted. Unfortunately, most of these forecasts were wildly off, forcing utilities and their ratepayers to pay hefty prices for electricity that, in many cases, the utilities did not need.

PURPA promoted construction of many wind turbines. In the Altamont Pass region of northern California (pictured on the cover), and in Tehachapi Pass (Figure 1), wind developers took advantage of notoriously generous standard contracts developed by the California Public Utilities Commission, as well as a 10% investment tax credit for wind and solar generation under the Energy Tax Act of 1978.<sup>6</sup> Developers built thousands of wind turbines, paid for by ratepayers, that blighted the landscape, but produced so little energy as to be derided as “PURPA machines.”



**Figure 1: Abandoned Wind Turbines - Tehachapi Pass**

<sup>6</sup> Pub. L. No. 95-618, 92, Stat 3174 (1978).

With passage of EAct,<sup>7</sup> the subsidies available to wind generation expanded. EAct enacted the federal PTC, the vast majority of which has been used by wind generators. According to the Congressional Joint Committee on Taxation, between 1992 and 2015, the PTC will cost taxpayers more than \$14.7 billion<sup>8</sup>, not including the additional \$9.95 billion<sup>9</sup> in stimulus funding and \$12.2 billion estimated cost of the proposed one-year extension of the PTC currently being debated in Congress. Thus, almost 35 years since passage of PURPA, wind generation continues to be subsidized heavily.

Subsidies distort competitive markets, drive out unsubsidized competitors, and reduce the incentives to innovate and improve efficiency. Moreover, even if one argued that wind generation was worthy of temporary “protection” when PURPA was enacted, surely after 35 years, the “infant” wind industry is fully grown.<sup>10</sup>

### III. WIND SUBSIDIES: PAYING FOR POWER THAT FAILS TO PERFORM WHEN IT IS NEEDED

One of the most difficult facets of wind generation is its variability. Because the wind does not always blow, the electric grid cannot rely upon wind generation the way it relies on fossil-fuel, nuclear, and hydroelectric generation. Because of its variability, wind generation must be “firmed-up” with additional reserves of fossil-fuel generation, typically gas-fired generators that can be ramped up and down quickly.

The value of any electric generating resource—whether conventional or renewable—*hinges on the ability to produce electricity when it is most valuable*, that is, when the demand for

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<sup>7</sup> Pub. L. 102-486, 106 Stat. 2866 (1992).

<sup>8</sup> M. Sherlock, “Energy Tax Policy: Historical Perspectives on and Current Status of Energy,” CRS Report R41227, May 7, 2010, Appendix B, Table B-5. In addition, under the ARRA, renewable energy developers can claim a one-time benefit in lieu of the PTC, called a “Section 1603 grant.” Total payments for Section 1603 grants are estimated to be \$22.6 billion through 2017. Through September, 2012, over 70% of the grants have been for wind generation.

<sup>9</sup> According to the U.S. Department of the Treasury as of September 10, 2012 approximately 9.95 billion has been awarded to wind projects through Section 1603 stimulus funding. See <http://www.treasury.gov/initiatives/recovery/Pages/1603.aspx>.

<sup>10</sup> The “infant industry” argument historically has been used to justify protection of domestic firms from international trade and was first developed by Alexander Hamilton at the beginning of the nineteenth century. The same sort of protectionist arguments have been used by renewable energy advocates to justify continued subsidization. A classic article discussing why infant industries should not be protected is J. Baldwin, “The Case Against Infant Industry Protection,” *Journal of Political Economy* 75 (1969), pp. 295-305.

electricity is greatest. Most electric utilities in the U.S. experience peak demand for power in July and August, as air conditioners hum on the hot and humid days that typically occur.

From the standpoint of both electric system planners, who are charged with ensuring the lights stay on, and consumers, who want uninterrupted access to electricity, it is critical to have sufficient generating capacity available when demand peaks. That is why, during the “dog days of summer,” generating plants fueled by coal, nuclear, and natural gas, almost always operate around-the-clock at full capacity. Also, system planners ensure they have sufficient “reserve” capacity, such as gas-fired combustion turbines, to bring on-line within minutes, to meet electricity demand on the hottest, most humid summer days.

**A. AVAILABILITY OF WIND POWER, 2009 – 2012**

We analyzed wind generation in three regions where there has been extensive—and rapid—development of wind power: PJM, which covers the mid-Atlantic states and the Ohio Valley; MISO, which covers much of the remaining Midwestern States; and ERCOT, which oversees the electric system in almost the entire state of Texas. (Figure 2) Together, these three regions account for about 27,000 MW of wind generating capacity, over half of the approximately 50,000 MW of installed wind generating capacity in the U.S.<sup>11</sup> With over 10,000 MW of wind generating capacity, ERCOT contains the most wind generation of any state.



**Figure 2: ISO/RTOs (Source: FERC)**

For each of these three regions, we collected data on hourly load (i.e., demand) and hourly wind generation over the period January 2009 – August 2012. We analyzed multiple years of data to account for possible anomalies in a given year’s weather that could affect both loads and wind generation, with each season defined as the months shown in Table 1.<sup>12</sup>

<sup>11</sup> Source: SNL Financial. Data through August 31, 2012.

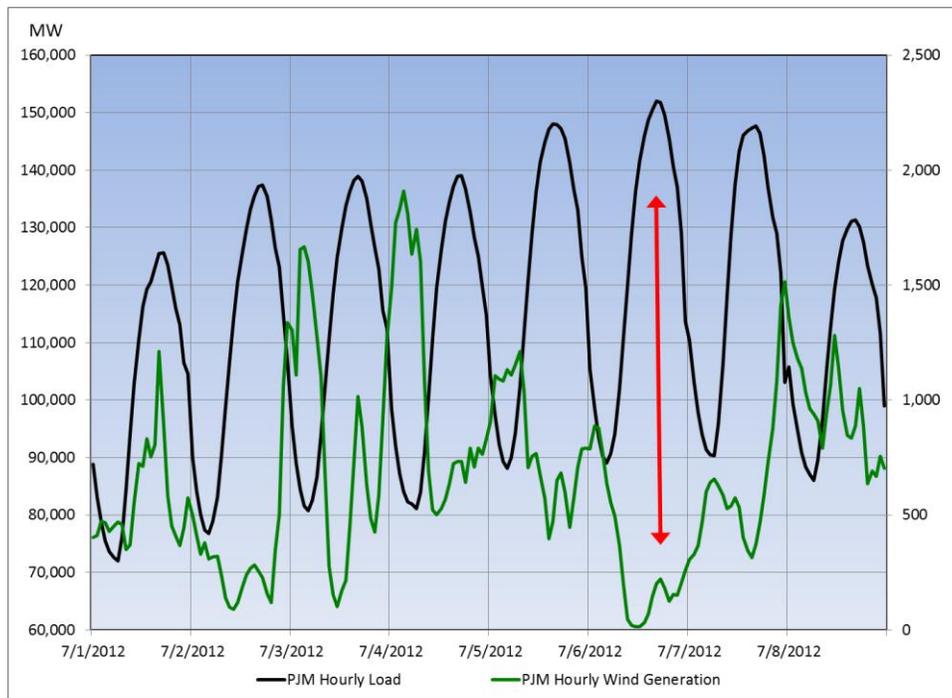
<sup>12</sup> The “Winter” season is defined contiguously. Thus, for example, Winter 2012 is defined as the three months December 2011 through February 2012.

Season	Months
Winter	December – February
Spring	March – May
Summer	June – August
Fall	September – November

**Table 1: Season – Month Mapping**

As discussed above, both from a system planning and customer perspective, we want generating resources to be available when electricity demand peaks. A generating resource that fails to produce when most needed has little value. Yet both on an hourly and seasonal basis, wind generation follows this adverse, low value

pattern, displaying a strong negative relationship between hourly load and hourly wind generation, that is, the greater the load, the less wind generation.<sup>13</sup> Figure 3, for example, shows PJM hourly loads and wind generation for the week of July 1 – 8, 2012, when much of the eastern U.S. was in the grip of a record heat wave. The pattern between hours with high loads and low wind generation is illustrated by the red arrow.



**Figure 3: PJM Hourly Load and Wind Generation, July 1-8, 2012**

As this figure shows, wind generation typically peaks during the night when the demand for electricity is lowest. In contrast, when the demand for electricity is greatest in late afternoon, much less wind generation is available. Thus, a large and harmful “gap” exists between hourly demand and wind generation, with the greatest gap often occurring when demand is greatest.

<sup>13</sup> The statistical term is the “correlation coefficient,” which can range from -1 (perfect inverse correlation) to +1 (perfect positive correlation). In Figure 3, the correlation coefficient between load and wind generation for the week of July 1-8, 2012 was -0.40, indicating a strong inverse relationship.

From a system planning standpoint, the demonstrated “gap” between high hourly loads and low wind output makes wind a far less valuable and far less reliable resource than conventional generating resources. This “gap” between peak electric demand and low wind generation is observable both on a daily and seasonal basis.

Figure 4 compares average wind availability by hour in ERCOT to average hourly electric demand in the summer, and on an average annual basis.<sup>14</sup>

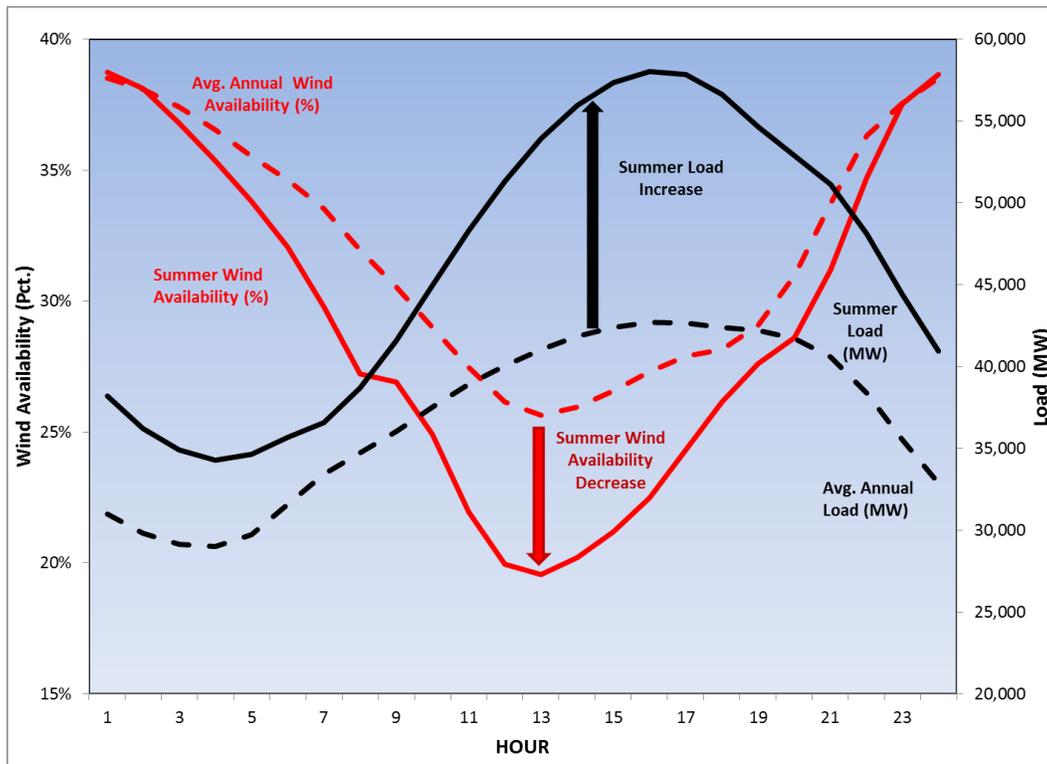


Figure 4: 2009-12, Summer and Annual Load and Wind Availability - ERCOT

As shown above, although average hourly loads in Summer are higher than during the year overall, whereas average wind availability is lower in Summer.

Figure 4 shows, the pattern of average hourly loads and average wind availability displays the same high load – low wind generation relationship: high load hours are associated with

<sup>14</sup> Wind availability is defined as the amount of wind generation relative to potential wind generation. We use wind availability, rather than actual wind generation, to account for the increase in total installed wind capacity over the period. For example, if total installed wind capacity is 5,000 MW and the average amount of wind generation at 6PM on a given day is 1,000 MW, then the wind availability factor for that hour is 20%.

low wind availability.<sup>15</sup> In other words, the hourly pattern repeats itself when seasonal load and wind generation are compared: when the demand for—and value of—electricity is greatest, there is less wind generation on average than during any other time of year. This relative lack of wind power is not surprising: the most miserable summer days are hot, humid, and still. Yet, it is an aspect of wind power that its advocates avoid discussing. So not only is wind generation’s output intermittent and unpredictable, available only when the wind happens to blow, but even more significantly, it rarely is available when power is needed most. Thus, each year, the PTC forces taxpayers to spend billions of dollars for a generating resource that produces the least amount of electricity when it is most valuable and most needed. That is like asking someone to pay for a taxi that does not show up when it’s raining.

We can also evaluate the load–wind “gap” in each season. We define this load–wind “gap” as the difference between the seasonal wind availability ratio and the seasonal load ratio. The seasonal wind availability ratio is defined as the average seasonal wind availability relative to average annual wind availability. Similarly, the seasonal load ratio is defined as the average load during the specific season relative to average annual load. For example, suppose the seasonal load in spring equals 90% of annual average load, but that seasonal wind generation is 120% of annual average wind generation. Then the load–wind “gap” equals 120% – 90%, or +30%. A positive load-wind gap value means there is relatively more wind generation available to serve load; a negative load-wind gap value means there is relatively less wind generation available to serve load.

Figures 5–7 illustrate the seasonal load-wind “gap” for ERCOT, MISO, and PJM over the 2009 – 2012 period.<sup>16</sup>

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<sup>15</sup> The correlation coefficient between average annual hourly wind availability and average annual hourly load is –0.83. The correlation coefficient for the Summer season is –0.74.

<sup>16</sup> Figures 5–7 omit the incomplete Winter 2009 season, as it would include December 2008 data. Similarly, Fall 2012 season data is omitted.

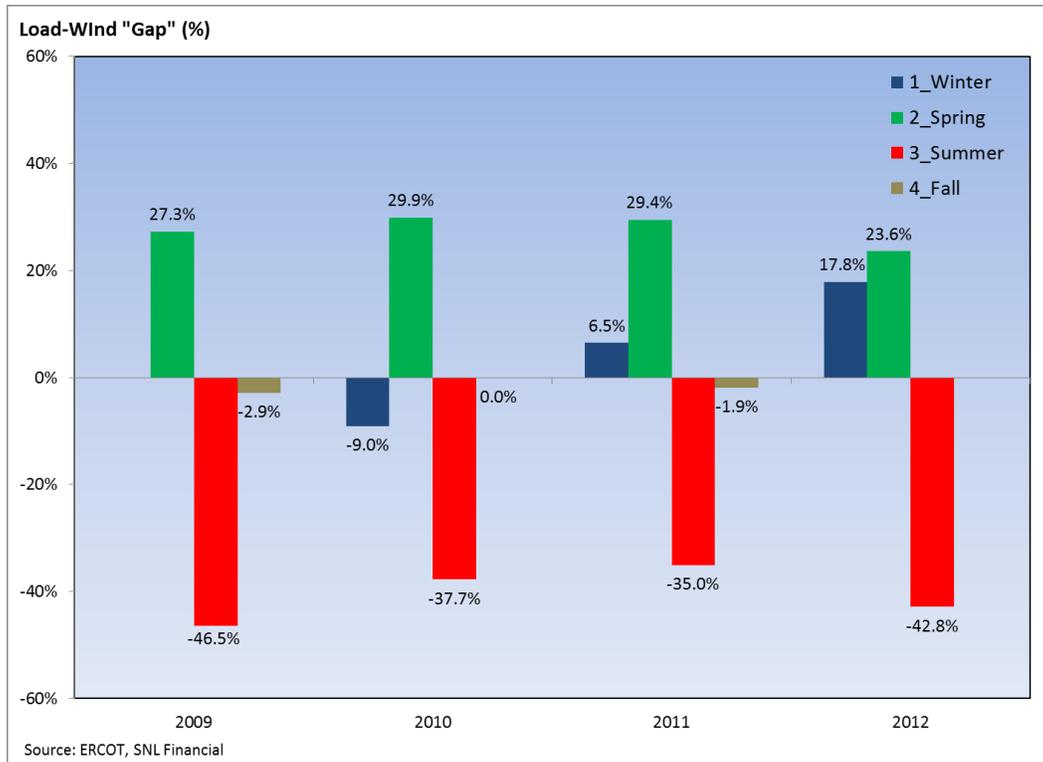


Figure 5: ERCOT Load-Wind Gap, 2009 - 2012

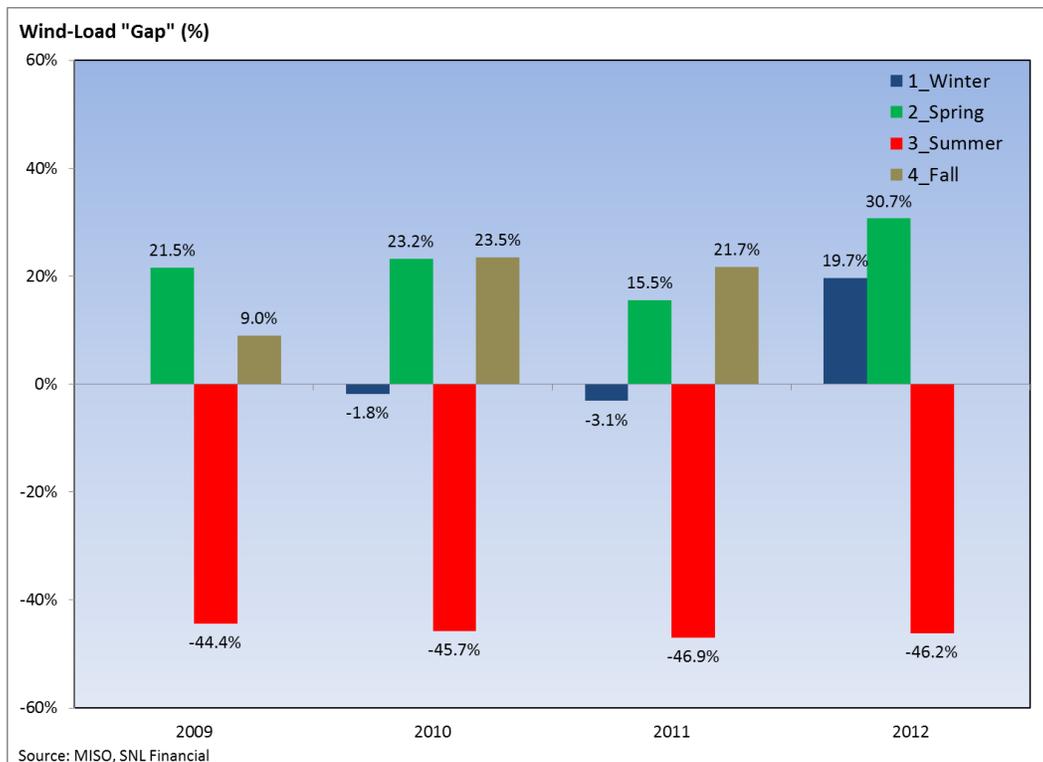


Figure 6: MISO Load-Wind Gap, 2009 - 2012

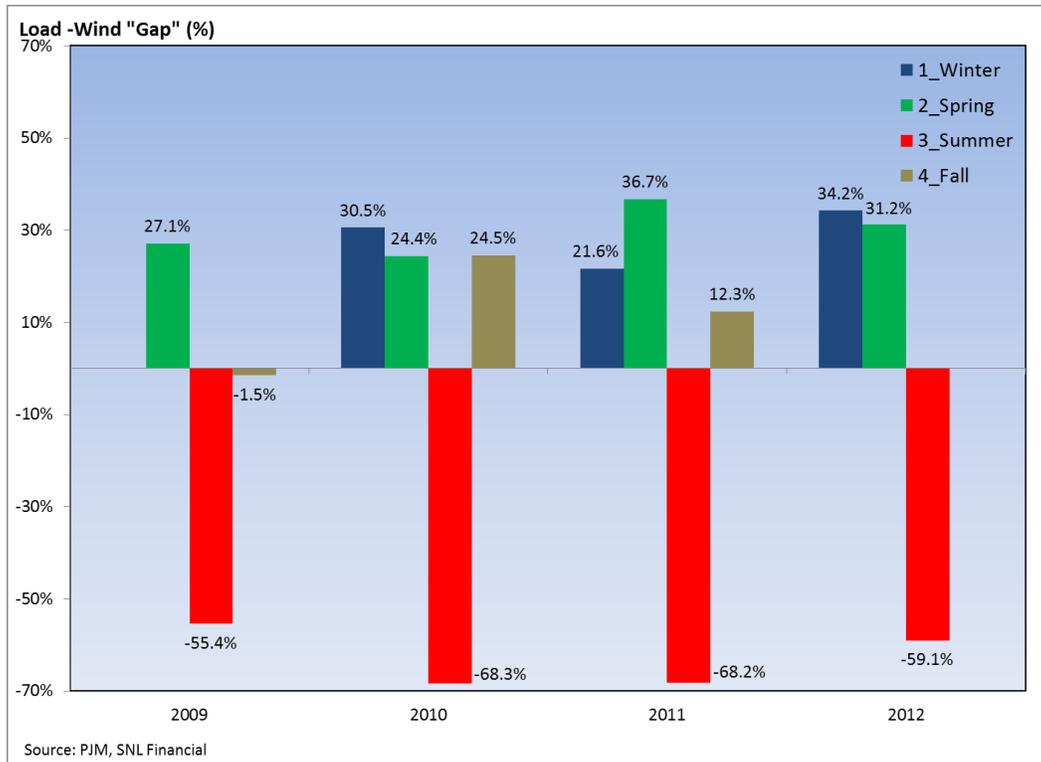


Figure 7: PJM Load-Wind Gap, 2009 – 2012

As these three figures demonstrate, the relative lack of wind generation in each region during the last four Summers is pronounced. In all three regions, the highest relative amount of wind generation occurred when loads were lowest, and the smallest amounts of wind were available when loads were greatest in Summer. In PJM, the effect has been particularly pronounced, with a summer load – wind gap of almost **-70%** in summer 2010 and 2011, and **-59%** in summer 2012. Chicago’s experience during Summer 2012’s searing heat wave provides a compelling local example of wind failure to provide power on the hottest days. During this heat wave, Illinois wind generated less than 5% of its capacity during the record breaking heat, producing only an average of 120 MW of electricity from the over 2,700 MW installed. On July 6, 2012, when the demand for electricity in northern Illinois and Chicago averaged 22,000 MW, the average amount of wind power available during the day was a virtually nonexistent 4 MW.<sup>17</sup>

<sup>17</sup> J. Lesser, “Wind Power in the Windy City: Not There When Needed” *Energy Tribune* (op-ed) July 25, 2012.

## B. WIND AVAILABILITY DURING PEAK LOAD HOURS

System planners are especially concerned about having sufficient generating capacity available, including “reserve” capacity, to meet future peak electric demand in subsequent years. In PJM, for example, which operates a separate wholesale capacity market, generators are paid a capacity “credit” based on their overall availability during the Summer peak period.<sup>18</sup> Because wind generation cannot be relied on in any given hour, currently PJM credits wind with an availability factor of 13%;<sup>19</sup> MISO 14.7%;<sup>20</sup> and ERCOT 8.5%.<sup>21</sup> Thus, a 100 MW wind farm is assumed to provide an average of 13 MW of summer capacity in PJM, and less than 15 MW in MISO. In marked contrast, conventional fossil fuel and nuclear resources typically have capacity credit factors of 90% or better. To keep the lights on, system operators therefore must rely on these more dependable conventional resources to make up the difference at an additional cost to consumers.

We examined wind availability at the time of the peak hour for the 10 highest load demand days in each year. As shown in Table 2, median wind availability (i.e., the percent of wind generation relative to installed capacity) during the 10 highest demand days each year is extremely low, especially in comparison with median annual availability.<sup>22</sup>

Region	Median Availability Peak Hr, Highest 10 Demand Days	Median Availability All Days, All hours
ERCOT	6.0% - 15.9%	30.9%
MISO	1.8% - 7.6%	27.0%
PJM	8.2% - 14.6%	25.9%

**Table 2: Median Wind Availability, Peak Hour, Top 10 Days 2009-2012**

For example, in ERCOT, the median wind availability during the 10 highest demand hours ranged between 6% and 15.9%, compared with an overall median availability of 30.9%, in

<sup>18</sup> The capacity credit is known as “unforced capacity,” or UCAP. For fossil-fuel and nuclear generating resources, UCAP is based on historic forced outage rates, which is measured as the percentage of the year a generating plant is unavailable because of an unplanned outage, such as caused by a maintenance issue. As discussed in Section IV.C, below, however, capacity credit percentages do not compensate for inaccurate forecasts of wind generation on a short-term (e.g., 1-4 day ahead) basis.

<sup>19</sup> Source: PJM, Manual No. M-21, *Rules and Procedures for Determination of Generating Capability*, Appendix B.3, p. 18.

<sup>20</sup> Source: MISO, Manual No. M-011, *Business Practice Manual, Resource Adequacy*, p. 4-27.

<sup>21</sup> ERCOT does not currently operate a separate capacity market, as do PJM and MISO.

<sup>22</sup> Measured as median wind generation during all hours, relative to installed wind capacity.

MISO median wind availability ranged between 1.8% and 7.6%, compared with an annual median availability of 27.0%, and in PJM, it ranged between 8.2% and 14.6% as compared to annual median availability of 25.9%.

Although we did not evaluate wind generation in the Southwest Power Pool (SPP), which has about 4,800 MW of installed wind capacity, the SPP Independent Market Monitor reports similar wind output behavior during peak load hours. In 2011, for example, wind availability during all peak hours averaged just over 15%, whereas in the hours where loads were lowest, wind availability averaged over 40%.<sup>23</sup>

#### **IV. SUPPRESSING MARKET PRICES WITH SUBSIDIZED AND INTERMITTENT WIND GENERATION DOES NOT BENEFIT CONSUMERS**

The intermittency of wind power and the clear patterns of the lowest wind availability when electricity demand is highest, refutes some PTC proponents' claims that subsidized wind generation "benefits" consumers by artificially suppressing market prices. This argument, most recently presented by the Center for American Progress (CAP)<sup>24</sup> is straightforward: adding subsidized electric supplies helps consumers because it suppresses the price of electricity. But while straightforward, the argument is also wrong, because it fails to address the adverse impacts of distorting competitive markets, which ends up harming the very consumers who are supposed to benefit.

At the heart of this argument is an economic fallacy that price distortions caused by government subsidies in a free market are "benefits." Setting aside justification of government subsidies because they distort markets, the reality is such policies never work, because they are a form of "free lunch" economics that fails to market dynamics. In other words, these arguments incorrectly assume that suppliers who see lower market prices will not change their behavior.

Of course, suppliers will change their behavior. Although forcing subsidized supplies into a competitive electricity market may temporarily reduce electricity prices, the market will respond relatively quickly. Existing power plants will shut down prematurely or abandon plans to expand. Potential market entrants, fearing further government intervention, will

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<sup>23</sup> SPP, Independent Market Monitor, *2011 State of the Market*, July 9, 2012, pp. 59-60. The Independent Market Monitor reports that similar wind availability patterns—decreasing availability as load increased—were observed in the three previous years.

<sup>24</sup> R. Caperton, "Wind Power Helps to Lower Electricity Prices," Center for American Progress, October 10, 2012.  
<http://www.americanprogress.org/issues/green/report/2012/10/10/41100/wind-power-helps-to-lower-electricity-prices/>.

not build new power plants, and investors will demand higher returns for the greater risks, raising the cost of capital for all suppliers. In the end, the market will lose as many, or more, megawatts of supply as it gains through subsidies, and will raise costs as well. Consumers will not pay less for electricity; they will pay more. Applying the “free lunch” logic, the government could “benefit” consumers by artificially subsidizing the price of all goods and services, or simply make all goods and services “free.” Of course, this is not true. On the contrary, these policies: (1) put consumers back in the same place they started from a supply and demand standpoint; (2) drive existing market participants out of business, and (3) increase U.S. debt associated with the subsidies, which must ultimately be paid by taxpayers. The problem is made worse because the PTC drives reliable generation out of the market and replaces it with intermittent wind generation that, as our analysis has shown, produces the least amount of electricity when customers need it most.

To understand the flaws in the “free lunch” logic, consider the market distortions caused by the PTC subsidy. Generators in the market bid against each other on an hourly basis. At the same time, each distribution utility tells the market operator how much power they need to buy. The market operator then stacks up the generators from lowest to highest bid. Then, starting at the lowest bid, the market operator adds up all of the bids until they have enough power to meet the distribution utilities’ demands. The last bid accepted becomes the “market clearing price”—the price distribution utilities pay for their power and the price that generators are paid.

The CAP report, for example, presents a hypothetical example with five different generators: a wind farm; a nuclear reactor; a coal-fired power plant; an efficient and modern natural gas power plant; and an older and less efficient natural gas plant. Figure 8 below reproduces the left-hand side of Figure 1 in the report. Each of the plants will offer to sell power at the price that covers their cost to produce electricity, and provides their owners with a return on investment. On the other side of the market, distribution utilities need to buy 3,000 megawatts of power. This means the market operator will then stack up the bids from lowest to highest and then add up the bids until enough power can meet the 3,000 megawatts of demand.

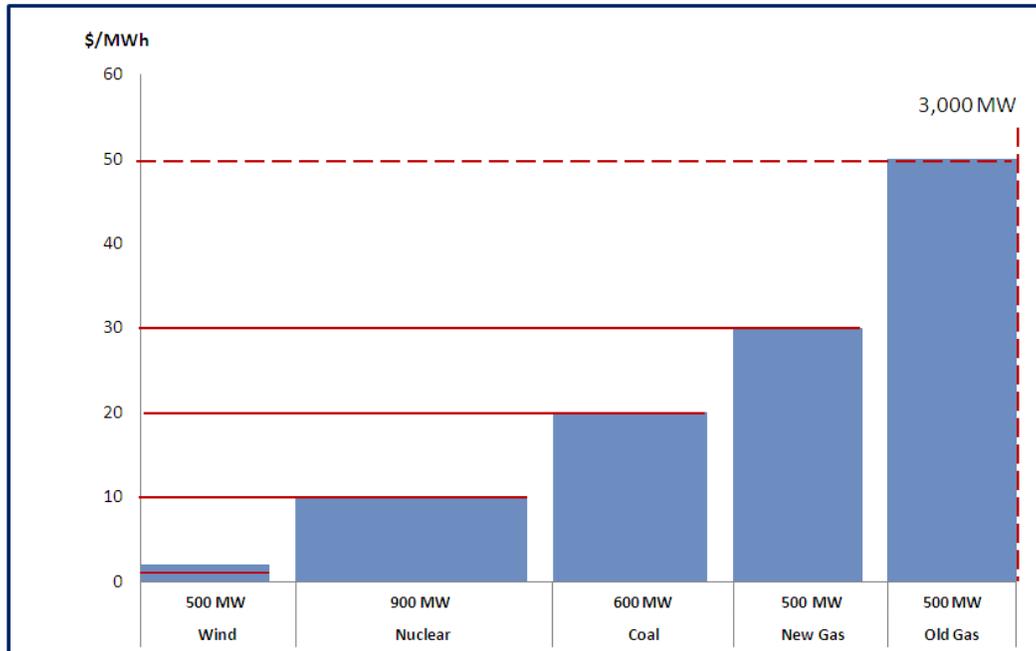


Figure 8: Market Clearing Price \$50/MWh

Initially, the market clears at \$50 per megawatt-hour of electricity. The report then goes on to explain dispatch costs when the government subsidizes a new 500-megawatt wind farm, as shown in Figure 9, which reproduces the right-hand side of Figure 1 in the report. In its hypothetical, the need for power has not changed, so the cheapest 3,000 megawatts will still determine the clearing price. In this case, the market now clears at \$30 per megawatt-hour of electricity.

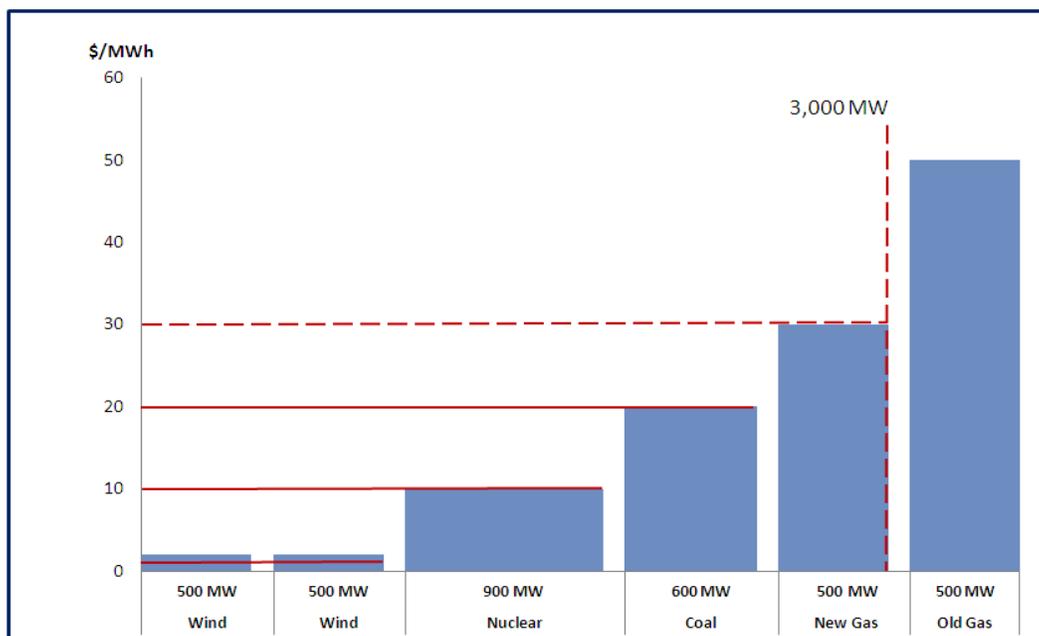


Figure 9: Market Clearing Price \$30/MWh

The report concludes that, because consumers pay \$20/MWh less than before, the subsidy benefits consumers and thus is good for society. However, from a market standpoint, the subsidized wind generation has simply transferred money from existing producers to consumers. The analysis stops at this point, but the market continues to respond. Specifically existing generators will respond to the lower market price by exiting the market. This is illustrated in Figure 10.

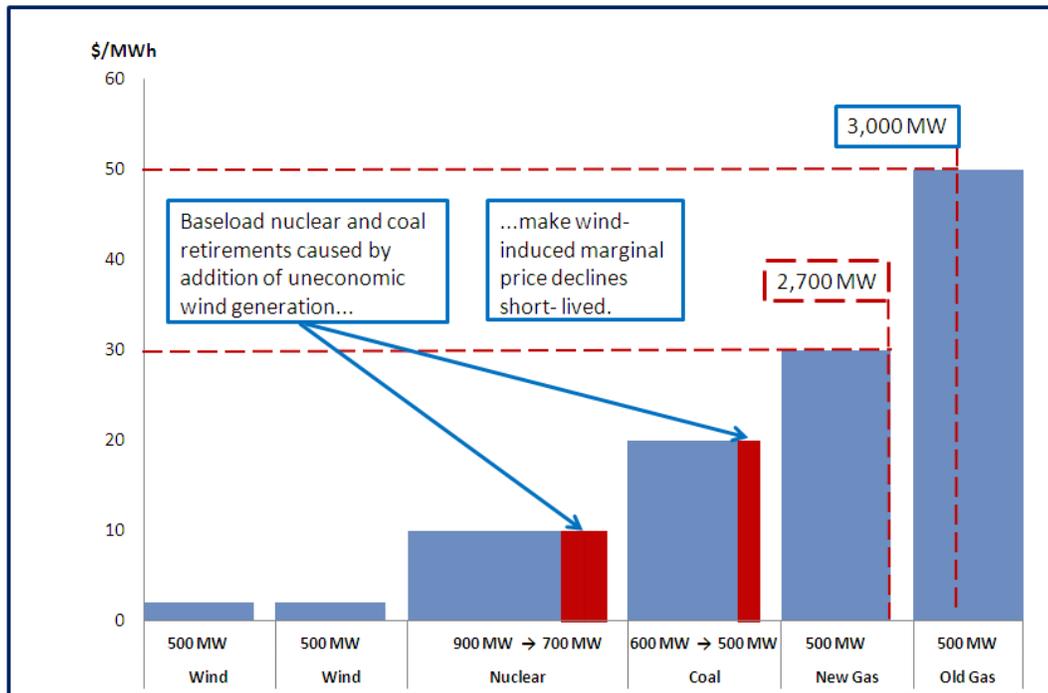


Figure 10: Impact of Generator Retirements

By lowering the market price initially, the subsidized wind generation drives unsubsidized generation from the market, through early retirements and less investment. In fact, this is happening. For example, PPL corporation recently announced it was considering shutting down its Correte coal-fired plant in Montana, stating:

“Wind farms can make a profit even in low demand time of the season . . . because they can pay people to take their electricity . . . There’s nothing wrong with wind. It’s a good, clean energy source. What we want to see is a level playing field for our plants. What bothers us is that there are actually companies paying people to take their power”<sup>25</sup>

<sup>25</sup> T. Howard, “PPL Montana Officials Discuss Potential Shutdown of Corette Plant,” Billings Gazette September 21, 2012.

In Figure 10, the nuclear and coal plant retirements shown are a dynamic response to the artificially low market price caused by government intervention. In this example, the market responds to uneconomic interventions with uneconomic retirements, i.e., retirements that would not have occurred but for the price distortion. The alleged price “benefit” disappears because the price returns to its pre-subsidy level. In fact, consumers are worse off. Not only do they end up paying the same, pre-subsidy price for electricity, they must also pay the added cost of the subsidy itself and the additional costs to integrate variable wind output onto the grid, as discussed in the next section.

Because of the observed lack of wind generation during peak hours, the final outcome is even worse for consumers. As discussed in the previous section, 1,000 MW of wind capacity is not the equivalent of 1,000 MW of conventional generation. As shown in Section III, data over the last four years demonstrates that approximately 85% of installed wind capacity fails to generate electricity when electricity demand peaks. Figure 11 illustrates the effect of the subsidy on days when wind fails to produce electricity. Because subsidized wind caused the early retirement of baseload generation, the lack of wind generation requires additional high-cost generation to be brought on-line to meet peak demand.

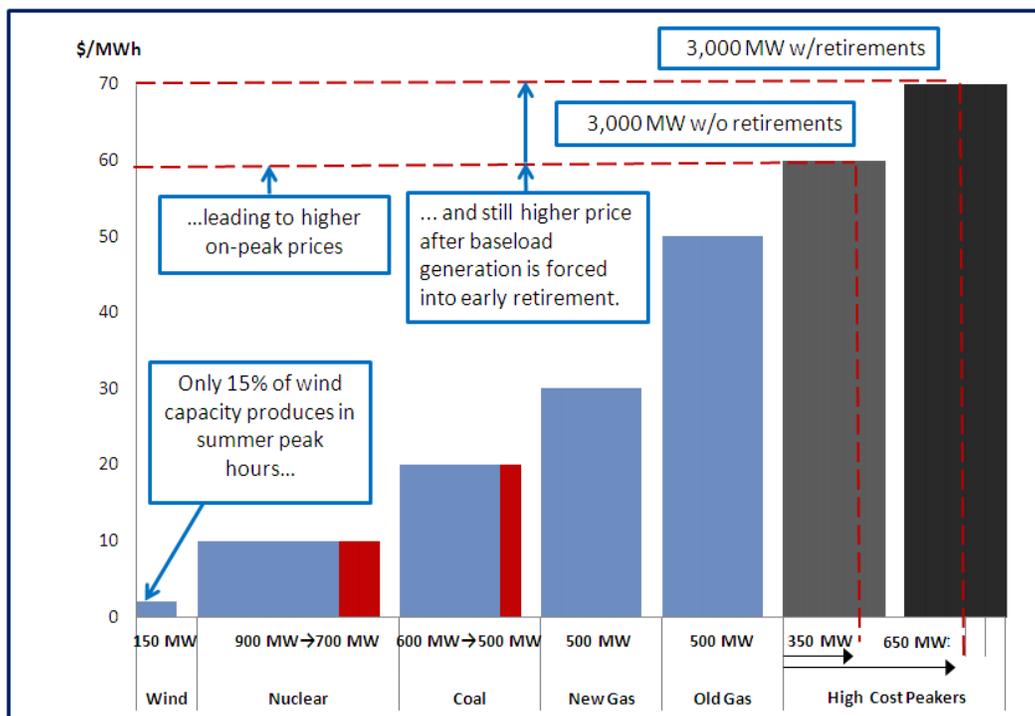


Figure 11: Market Impact - High Demand Hours

In this example, the 1,000 MW of wind produces only 150 MW of generation on peak. As a result, higher cost peaking units must be brought on-line to meet demand. If no conventional generation retires, 350 MW of peaking generation must be brought on-line, which raises the market price to \$60/MWh. However, because the subsidized wind

generation has caused 300 MW of conventional generation retirements, an additional 300 MW of peaking generation, or a total of 650 MW, must be brought on-line to peak demand, further raising the market price to \$70/MWh. As a result, consumers now pay \$20/MWh more for electricity than they would have paid if the subsidy were not in place.

Of course, in reality, the impacts of the lost revenue on plant investment, market price, and reliability are far more complicated than these simple scenarios suggest. But the idea that we can somehow “trick” the market with subsidies for wind without long term impacts on reliability is an unrealistic example of “free lunch” economics.

Ironically, while promoting subsidies to suppress market prices, the CAP report acknowledged that undermining price signals through the subsidized introduction of wind energy can lead to problems “in the future” because “we want to make sure that our power system encourages investment in the power plants that make our economy work.”<sup>26</sup> The promotion of continued subsidies for wind means the future is now.

## V. THE ADDITIONAL COSTS OF SUBSIDIZED WIND POWER

The direct subsidies wind generation receives under the PTC are not the only costs taxpayers and ratepayers must bear. In addition, ratepayers must pay for: massive transmission system investment needed to interconnect wind resources; stand-by generation to back-up or “firm” wind’s sudden lack of availability when it stops blowing; and additional ancillary service costs to ensure voltage and frequency levels remain within operating limits in spite of wind’s volatility.

### A. LOCATION, LOCATION, LOCATION

Another problem with wind generation is that it has a much lower power density than traditional generating resources.<sup>27</sup> Because of that, wind requires huge quantities of land compared to traditional generation. For example, a typical wind farm has a power density of about 5 MW per mile. That is far less than the power density of a typical coal-fired plant, including the land used for mining coal. Moreover, this comparison does not even account

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<sup>26</sup> *Id.* at 4.

<sup>27</sup> Power density is expressed generating capacity per unit area. Currently, wind generation has a power density of about 2 watts per square meter (w/m<sup>2</sup>), which is equivalent to about 5 MW per square mile. See, e.g., V. Smil, “Power Density Primer: Understanding the Spatial Dimension of the Unfolding Transition to Renewable Electricity Generation,” Parts I –May 14, 2010, <http://www.vaclavsmil.com/wp-content/uploads/docs/smil-article-power-density-primer.pdf>; R. Bryce, “Get Dense,” *City Journal*, Vol. 22 (Winter 2012). [http://www.city-journal.org/2012/22\\_1\\_environmentalism.html](http://www.city-journal.org/2012/22_1_environmentalism.html).

for the intermittency of the actual wind power produced, which further reduces the power density of wind relative to conventional generation.

The large land requirements for wind generation encourage development in less populated areas, far from load centers, where land is less costly. One consequence is that connecting wind resources to the high-voltage transmission grid requires significant investment in high-voltage transmission. In ERCOT alone, for example, the cost of new transmission infrastructure for wind generation has been \$6.9 billion, 40% greater than originally projected.<sup>28</sup> That amounts to over \$1,000 for a family of four.

## **B. OPERATIONAL COSTS**

Because electricity cannot be stored cost-effectively, electricity demand and supply must be balanced at all times. Otherwise, frequency changes and the resulting changes in voltage levels can exceed operating tolerances. In extreme cases, the power system can fail.<sup>29</sup> As a result, providing reliable electric service entails continually monitoring demand and scheduling generating resources to match demand.

As significant quantities of wind power are integrated into bulk power systems like PJM, MISO, and ERCOT, system operators must increase the amount of operating reserves and regulation reserves to ensure the system operates correctly.<sup>30</sup> The inherent variability of wind generation increases the uncertainty that power system operators must address on a day-to-day and even minute-to-minute basis.

Many of these operational costs are “socialized” among all participants. In other words, if a wind generator’s output suddenly falls when the wind drops off, the operational costs of compensating for that sudden output loss will not be borne entirely by the wind generator, but instead will be paid by everyone.

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<sup>28</sup> Source: Public Utilities Commission of Texas, Competitive Renewable Energy Zone Program (CREZ) Oversight, CREZ Progress Report No. 8, July 2012, p. 6. The original cost of the program was estimated to be \$4.9 billion.

<sup>29</sup> For example, if the frequency drops in your home, you may see the lights dim.

<sup>30</sup> Operating reserves include generating resources such as natural gas that can respond to changes in demand and can be available to meet sudden outages, load forecasting errors, and frequency regulation. Regulating reserves are generators whose output can be adjusted automatically from moment to moment to ensure the power system operates at the correct frequency.

Identifying the operational costs attributable to wind generation requires complex power system simulation models. One such study was published by the National Renewable Energy Laboratory (NREL) in February 2011.<sup>31</sup> That study estimated the additional costs to integrate wind generation (not including additional transmission system investment) at about \$5/MWh (in 2009\$). With over 50,000 MW of wind generating capacity installed in the entire U.S., and assuming that wind's average availability is 30%, this translates into over \$500 million in additional operating costs associated with subsidized wind generation; costs that are ultimately paid by electricity consumers. Table 3 provides an estimate of wind integration costs for ERCOT, MISO, and PJM for calendar year 2011.

Region	Estimated Wind Integration Costs (Millions of 2009\$)
ERCOT	\$141.2
MISO	\$102.1
PJM	\$46.3
<b>Total</b>	<b>\$289.6</b>

Table 3: Wind Integration Costs, 2011

As this table shows, using the NREL report integration cost estimates, the additional wind integration costs for just these three regions in 2011 totaled about \$290 million.

### C. INACCURATE FORECASTS OF WIND GENERATION, SYSTEM RELIABILITY, AND COST

To ensure the lights stay on, power system planners' ability to predict the amount of wind generation that will be available several days in advance is critical as the amount of wind generation determines how much fossil-fuel back-up generation must be available. Although even wind advocates acknowledge wind's inherent intermittency they claim wind generation can be predicted accurately several days in advance, allowing system operators to reduce, if not eliminate, the impacts of wind's volatility.<sup>32</sup> In other words, proponents argue that, because wind generation can be predicted accurately, wind does not impose higher reliability costs than conventional generating resources.

Notably, however, forecast and operational data in areas including ERCOT, as well as in European countries,<sup>33</sup> do not support such forecast accuracy claims. In addition, wind's

<sup>31</sup> NREL, *Eastern Wind Integration and Transmission Study*, NREL/SR-550-47086, Revised February 2011. <http://www.nrel.gov/docs/fy10osti/47086.pdf>. The wind integration costs are in addition to billions of dollars in transmission costs. See, e.g., the *MISO Multi Value Project Portfolio Results and Analyses*, January 10, 2012 p. 87 (The cost of the recommended MVP portfolio in 2011 dollars is \$5.2 billion).

<sup>32</sup> See, e.g., M. Delucchi and M. Jacobson, "Providing All Global Energy with Wind, Water, and Solar Power, Part II: Reliability, System and Transmission Costs and Policies," *Energy Policy* 39 (2011), pp. 1170-1190.

<sup>33</sup> K. Forbes, M. Stampini, and E. Zampelli, "Are Policies to Encourage Wind Energy Predicated on a Misleading Statistic?" *The Electricity Journal* 25 (April 2012), pp. 42-54 (Forbes et al, 2012).

volatility can be significant. For example, on October 28, 2011, wind generation decreased in MISO by 2,700 MW in just two hours. In ERCOT, on December 30, 2011, wind generation decreased 2,079 MW in one hour and over 6,100 MW between 6AM and 4PM that day.<sup>34</sup>

Moreover, even substantially reducing the capacity factor for wind generation, as done in ERCOT, MISO, and PJM, does not compensate for the significant forecast accuracy problem. Capacity de-rating addresses long-term planning issues: how much installed capacity must an electric system have one year from now to ensure there are sufficient reserves to meet future peak demand. In contrast, short-term planning issues are focused on the availability of generating resources over the next several days, specifically how much electricity these resources will provide to the power grid. Determinations that wind availability averages about 30% each year are meaningless in this context. As Forbes, et al. stated in their April 2012 study, “Capacity weighting is a distortion because the reported error understates the magnitude of the forecasting challenge.”<sup>35</sup>

In ERCOT, for example, the Texas Reliability Entity measures the difference between the actual and scheduled levels of generation. This measure, called “Schedule Control Performance Standard 2” (SCPS2), measures how closely a generator that is scheduling power keeps to its predicted schedule.<sup>36</sup> To meet this standard, the SCPS2 score must be 90% or higher. In their 2012 study, however, Forbes, et al. determined, “During the month of March 2009, 35 out of 36 Non-Wind Only Qualified Scheduling Entities (QSEs) satisfied the reliability standard. None of the 30 Wind Only QSEs met the standard. This is not an isolated case.”<sup>37</sup>

Furthermore, the demonstrated inaccuracy of short-term forecasts of wind generation increases the overall cost of meeting electric demand as system planners must reimburse other generators who had been scheduled to operate, but were not needed because actual wind generation was greater than forecast, or had not been scheduled, but were required to operate because actual wind generation was less than forecast. Although generators can

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<sup>34</sup> Another example of wind generation variability took place on October 16, 2012. On that day, wind generation on the Bonneville Power Administration system was 4,300 MW, accounting for 85% of total generation in the pre-dawn hours. The next day, wind generation fell almost to zero. See “In a first, wind exceeds hydro in BPA region,” Platt’s *Megawatt Daily*, October 19, 2012, p. 9.

<sup>35</sup> Forbes, et al., 2012, p. 46.

<sup>36</sup> A formal definition of SCPS2, which is based on ERCOT Protocol 6.10.5.3 “SCE Monitoring Criteria,” can be found at the Texas Reliability Entity website:  
<http://www.texasre.org/compliance/datasubmit/sce/Pages/Default.aspx>.

<sup>37</sup> Forbes, et al, 2012, p. 52. Average wind availability for the month of March 2009 was 34%.

be penalized for erroneous forecasts, most of the resulting system costs are socialized across all users.

## **VI. CONCLUSIONS**

Wind generation has been actively subsidized for 35 years, first under PURPA and the ETA, both enacted in 1978, and then through the PTC under the 1992 EPAct. After over three decades of increasing subsidies and increasingly stringent environmental mandates for fossil-fuel resources, it is past time for the well-established wind industry to stand on its own two feet. As such, the federal PTC subsidy should be allowed to expire under current law.

The PTC represents bad energy policy and bad economics for at least three reasons. First and foremost, wind generation's production pattern not only is volatile and unpredictable, but even more significantly, is "economically backward": producing the least amount of energy when loads are highest and electricity is most valuable. Second, subsidized wind generation also exacerbates artificially low electric prices, thus imposing economic harm on competitive generators that are needed to maintain system reliability. Third, the inability to forecast actual wind generation accurately increases system reliability costs, which are borne by all customers.

Given these demonstrated adverse characteristics of wind power, there is no economic or policy justification for its continued subsidization through the PTC.